WG2 Demand Response Evaluation: Process Evaluation Update

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Prepared for: Working Group 2 Evaluation Committee
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Overview of Handout

- CPP/DBP Participation Update
- CPP/DBP Process Evaluation Update
- Initiation of CPA-DRP Evaluation
- Initiation of Interruptible Evaluation
- Non-Part Market Survey Top-line

CPP/DBP Participation Update

CPP and DBP Program Signup (early Aug '04)

3 IOUs	Participants	Participant Account MW Sum*	Participant Account GWh Sum	CPP Participants	DBP Participants
Size					
Very Small (100-200 kW) - SDG&E Only	7	1	3	6	3
Small (200-500 kW)	266	83	401	42	226
Medium (500-1000 kW)	214	152	599	61	154
Large (1000-2000 kW)	115	156	631	28	92
Extra Large (2000+ kW)	86	497	2,481	12	75
Business Type					
Commercial and TCU					
Office	47	38	149	9	42
Retail/Grocery	152	55	315	1	151
Institutional	68	108	457	30	39
Other Commercial	90	96	408	23	72
Transportation/Communication/Utility	66	50	152	27	39
Industrial and Agricultural					
Petroleum, Plastic, Rubber and Chemicals	54	89	395	6	48
Mining, Metals, Stone, Glass, Concrete	44	148	847	4	40
Electronic, Machinery, Fabricated Metals	78	144	716	19	58
Other Industrial and Agriculture	86	159	671	27	60
Unclassified					
Unknown	3	2	4	3	1
Not in Frame	89	na	na	20	70
Total Accounts	777	889	4,114	169	620
Utility Breakdown					
PG&E	196	281	1,207	114	88
SCE	503	538	2,573	8	495
SDG&E	78	71	334	47	37

*Diversified customer peak demand

CPP/DBP Event Results to Date

Utility	Event	Event Date	Event Hours	Program Signups*	# DBP Bidders	# Accts Receiving Payment	Avg Hourly Reduction	Max Hourly Reduction	Estimated Payment
SDG&E	DBP - #1	5/3/2004	3-5 pm	25	6	3	0.6 MW	0.7 MW	$ 526
SDG&E	DBP - Test #1	6/30/2004	3-7 pm	37	9	5	1.1 MW	1.4 MW	$ 1,844
SDG&E	CPP - #1	7/13/2004	11-6 pm	42	N/A	N/A	4.4 MW	7.0 MW	N/A
SDG&E	CPP - #2	7/22/2004	11-6 pm	42	N/A	N/A	4.0 MW	6.0 MW	N/A
SDG&E	CPP - #3	8/11/2004	11-6 pm	47	N/A	N/A	3.7 MW	5.8 MW	N/A
SCE	DBP - Test #1	11/19/2003	3-8 pm	87	6	1	1.0 MW	2.0 MW	$ 1,133
SCE	DBP - Test #2	6/9/2004	3-7 pm	473	21	16	17.8 MW	19 MW	$ 31,222
SCE	CPP - #1	7/14/2004	12-6 pm	8	N/A	N/A	0.8 MW	0.9 MW	N/A
SCE	CPP - #2	7/22/2004	12-6 pm	8	N/A	N/A	0.9 MW	1.1 MW	N/A
SCE	CPP - #3	8/11/2004	12-6 pm	8	N/A	N/A	1.0 MW	1.2 MW	N/A
SCE	CPP - #4 - 2-day notice	8/12/2004	12-6 pm	8	N/A	N/A	1.0 MW	1.2 MW	N/A
PG&E	DBP - Test #1	7/26/2004	4-6 pm	78	N/A	22	26.4 MW	26.7 MW	$ 12,848
PG&E	CPP	8/27/2004	12-6 pm	~ 114	N/A	N/A	TBD	TBD	N/A

* In some instances not all signups were notified of event

****These are preliminary Utility numbers that have not necessarily been verified****

CPP/DBP Event Lessons Learned
(Caveat – From *limited* events to date)

- **PG&E**
  - Day of DBP Events based on "Committed Load"
    - In 1st event 27 accts had baselines < Committed Load (CL)
    - Those with high CL may drop large load but receive no payment if <50% CL
    - Those with small CL may drop large load and receive very small payment if > 150% CL
  - Confusion with Mandatory Event notification
- **SCE**
  - Conservative Bids
  - Low level of DBP Bidding in Initial Event
- **SDG&E**
  - Max Hourly reduction 150% of Average Hourly Reduction
  - One customer experienced exceeded their normal billing peak coming out of CPP event
  - Trouble with outbound dialer, AE's placed calls but only 7-8 customers contacted

Summary of Impact Evaluation/Baseline Procedures

- **3 Baselines being evaluated**
  - CPP/DBP method: High 3 days out of 10
  - Alternate #1: 10 days out of 10
  - Alternate #2: 10 days out of 10 with Scalar Adjustment (similar to CPA-DRP)
- **Measurement – Bias, Variability, Prediction Accuracy**
- **Interval data collection (Jan 2003- present)**

Participant Feedback to Date on Expected Activity Levels

- **Customer discussions to date indicate that slightly more than 1/2 of participants intend to actively respond to DBP or CPP events**
  - **NOTE – Results may not be representative, mostly SCE DBP**
- **The most common reasons given by potential non-responders:**
  - Curtailment Strategy not defined
  - Won't curtail due to operational or occupancy concerns
- **Potential active responders are nearly evenly divided between:**
  - Low to Moderate Probability of Response (<50% chance per event)
  - High Probability of Response (>50% chance per event)

CPP/DBP Process Evaluation Update

Current Efforts

- **Current effort focuses on implementation (March report focused on marketing)**
  - Documentation of enrollment and reporting procedures
  - Implementation experience to date
  - Program manager and implementation staff interviews and document review

Summary of Feature Variation

IOU	Eligibility	Processing Time	Flow chart or checklist?	DBP Load Reported	Monthly Notification Test?	CPP Events	CPP peak price	Day-of DBP event
PG&E	>200 kW	Anywhere from 2 days to 4 weeks; higher end if meter and phone to be installed and baseline established; CPP can't start until new bill cycle	Yes	Committed Load	Yes	one day ahead	5 times normal on-peak rate	Notifies of system emergency reduction between 12 and 8; customers must reduce by amount of committed reduction (no bids) within 1 hour for up to 4 hours
SCE	>200 kW	From 10-20 business days if meter in place; 4-6 weeks if meter and phone to be installed	Yes	15% of prior year average on-peak demand	No	one day or two days ahead (can cancel two-day on day before)	5 times normal on-peak rate	Notifies by 12, accepts bids until 1, notifies of acceptance by 2
SDG&E	>100 kW	Less than 5 days if meter in place; 2-3 weeks if meter to be installed	No	Committed Load	No	one day ahead	10 times normal on-peak rate	Notifies by 12, accepts bids until 1, notifies of acceptance by 2

CPP/DBP Process Evaluation Update

- **Early Marketing/Implementation Issues**
  - Issues with customers not able to reach 100 kW reduction
  - Process/timing for truing up enrolled reduction estimates versus actual results?
  - Little interest in transitional incentives
  - Learning curve for reps, staff, customers
    - (New rates, programs, technologies)
- **Changes in Marketing**
  - SCE clarified 100 kW DBP minimum (but effects linger)
  - Expanded DBP eligibility (DA out-in-out-in?)
  - More customer-friendly CPP bill protection
  - What will be the effect of new voluntary programs?

CPP/DBP Implementation Findings

- **Good communication/cooperation between DR program staff and account executives**
- **Relatively smooth implementation process, but continued concerns about contract complexity**
- **Most CPP/DBP customers take from 1-4 weeks to get into the system if meter present**
  - PG&E and SCE have flow charts and/or check-off system, but SDG&E reports quicker turnaround
  - Bottlenecks include participation in non-compatible programs, DA vs. bundled, insufficient load to qualify
  - Generally more delays on customer end (legal sign-off, failure to sign all documents, missing data); less than 10 percent of potential sign-ups abort because of customer legal/corporate concerns

CPP/DBP Implementation Findings (cont.)

- **Need to install meter and phone lines creates longer delays**
  - Most new customers currently have the meters and software they need
  - SCE no longer pays for R-10 meters for program participants (less effective tracking)
  - SDG&E tariff modification says that customers who have meter installed must participate in 10 DBP events or pay for installation, but this has not yet been a problem
- **Meter installation may become more of an issue as marketing focuses on smaller accounts, particularly for SDG&E**

CPP/DBP Implementation Findings (cont.)

- **How is load associated with enrollments reported?**
  - For CPP, all utilities report 15% of previous year's average on-peak demand
  - For DBP, SCE reports 15% of previous year's average on-peak demand, aggregated across all participants
    - Smaller customers would have to bid much more than 15% to reach 100 kW minimum
    - Limited experience with test events suggests much less than 15% will be bid and delivered
  - For DBP, PG&E and SDG&E report "committed load"
    - As a percentage, committed closer to 60% than 15% of average peak demand
    - Events to date suggest some of these may be unrealistic

CPP/DBP Event Experience To Date

- **DBP**
  - All utilities have had one test event this summer
  - SDG&E had actual event
- **CPP**
  - SCE and SDG&E have had 3 or more events
    - Goal is to have 12 per summer
    - Utilities are tweaking trigger temperatures, using “soft” triggers

CPP/DBP Event Experience To Date (cont.)

- **Notification process**
  - For SDG&E and SCE, some calls from customers regarding account log in, lost passwords on initial DBP events
    - Some customers missed initial notification because they were out to lunch, away from their computer, etc.
    - Some test events haven't had external stimuli – heat, system warnings – to alert customers to event likelihood & reinforce resource need
  - Some account reps have also made courtesy calls
  - PG&E tests notification process monthly
  - SDG&E program manager explicitly told customers about pending DBP test event to encourage learning
  - No feedback from customers regarding problems with CPP notification

CPP/DBP Event Experience To Date (cont.)

- **Bidding process**
  - Percentage of eligible customers submitting bids/load has ranged from less than 5% to about a third
  - Customers often overbid or underbid (only 25 of 42 customers who bid in SCE and SDG&E events received payments, and often for much less than they shed)
  - PG&E does not accept bids for day-of events
    - 22 paid of 31 that reduced more than 100 kW
    - PG&E also had some reductions >150% of committed that was not paid
    - Notification says event is mandatory and customers must respond, may lead to confusion
    - Source of committed levels? Need to adjust?

CPP/DBP Recommendations and Next Steps

- **Recommendations**
  - PG&E day-of DBP event modification
  - Review requirement for day-of testing only
  - Coordination of DBP capacity reporting
  - Initiate CPP events for PG&E
  - Notification testing for rarely called programs
  - Customer follow-up to address over/under bidding
  - Coordination of eligibility expansion
- **Next Steps**
  - Assess customer response to events
  - End-of-summer participant survey (satisfaction, lessons learned, etc.)
  - Observe effect of voluntary programs on marketing effort

Initiation of Evaluation of CPA-DRP Program

CPA-DRP Initial Evaluation Scope

- **Initial Scope: Review of program to raise issues**
- **Interviews with program managers, CPA, APX, two aggregators**

CPA-DRP Background

- History – product of energy crisis
- Numerous and frequent changes over past several years
- Participation – small number of large customers; (400 MW cap said to be attainable)
- Few events (mostly test) in 2003-2004
- Shift to utility dispatch under way
- Current project status?

CPA-DRP -- Operation

- **Players: CPA-DWR-Aggregators-APX-IOUs-MDMAs**
  - Aggregators market, sign up customers, with help from utility reps
  - Lengthy signup process because billing cycles need to change (APX needs cleaned customer data on a monthly basis to calculate payment)
  - Customers commit 7 to 2 days before end of month (basis for capacity payment), additional capacity can be nominated in day-ahead market
  - Utilities report nominated capacity provided by APX, but don’t know how responses are “trued-up” for payment: i.e. performance is not known

CPA-DRP -- Strengths

- Gives DA customers a way to participate in DR
- Customers get paid for capacity plus energy
- Third party participation allows competitive marketing (e.g. no out of pocket penalty)
- Appears to be ample interest if a stable program can be developed

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CPA-DRP -- Weaknesses/Issues

- **Huge degree of uncertainty**
  - Will CPA exist?
  - Will DRP program exist? In what form?
    - Delays in finalizing Summer 2004 features
  - Who will dispatch?
    - Delays in signing of agency agreement
    - Lack of direction from CPA
- **Complex, with multiple players**
  - Utility reps can be valuable in marketing program, but don't know price, and see a risk if they market the program and then if program or CPA goes away, lose credibility
  - Utilities have not gotten information on program performance beyond monthly reservation
  - Concerns with delayed payments last year
  - DWR testing could use up hours and limit IOU dispatching capability

CPA-DRP -- Weaknesses/Issues (cont.)

- **Negative design changes from last year**
  - Went from day ahead to day-of (yet “reservation” does not commit DWR)
  - Lower incentive
  - More uncertainty regarding hours called
  - All at least 3 hours (vs. 2 hour minimum last year)
- **Organization**
  - Multiple players with conflicting goals
  - DWR has a cost minimization perspective; not interested in building capability
  - No one appears to take strong ownership of the program
  - Utilities want to handle dispatch – happening soon?

CPA-DRP -- Weaknesses/Issues (cont.)

- **Timing**
  - Aggregators need well defined rules early enough to support marketing
  - Signups take a long time because of meter installation, communication, and billing cycle issues
  - APX has to coordinate data from various sources
- **Bottom line – a program should be in place by at least April to firm up summer resources**

CPA-DRP -- Recommendations/Next Steps

- **Preliminary Recommendations**
  - Pick a program and stick with it
  - Increase information on performance to utilities
  - Provide some assurance of continuity
  - Clarify State/CPUC policy objectives (e.g., maximize DR resource versus DWR cost minimization)
- **Next Steps**
  - Aggregator interviews
  - Customer interviews

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Initiation of Evaluation of Interruptible Programs

Interruptible -- Initial Evaluation Scope

- **Initial Scope: Identify Important Process Issues for Ongoing Program Development**
- **Project Manager/Utility Staff Interviews**

Rate Structures, Eligibility & Other Requirements

- **Traditional Reliability- -Triggered IRs:**
  - SDG&E's AL TOU CP has changed: now price-based, more like CPP now – different from I6 & Sched 19/20
  - I6, Sched 19/20 & BIP: 500 kW minimum customer size & interrupt impact – Firm Service Levels set by customer
  - FSLs eliminate baseline vs. actual load problems.
  - Availability varies: Sched 19/20 Closed, I6 closed except "new" load, AL TOU CP open to backup generation customers
  - High penalty rate presents high risks for some customers

Rate Structures, Eligibility & Other Requirements (cont.)

- **Newer Reliability-Triggered IRs:**
  - SLRP – Legislated (SB1X-5 dated 4/11/01), but out of synch with customer and utility value
  - BIP – good potential, focus is on peak. Trad'l IRs called first in events & when all hrs used then BIP is implemented
    - $6/kWh penalty may be too onerous (though ensures action)
  - OBMC – Circuit basis is theoretically interesting but forces "lead customer" issue where >1 customer on the circuit
    - $6/kWh penalty also an issue here
  - RBRP – Simple, low cost, focused

Rate Structures, Eligibility & Other Requirements (cont.)

- **In general, little action since crisis, so hard to judge retention effects of structural changes:**
  - (Negative) Effects of high penalty rates should # of events increase and customer response is more severely tested
  - Caps on frequency & duration of events – (positive) effect on retention
  - Ongoing interplay with CPP, DBP, DRP efforts

Marketing and Sign-up

- **Emphasis on price-triggered DR – less attention paid to reliability-triggered rates**
- **Few new customers since crisis:**
  – Traditional IRs either closed or constrained
  – SLRP, BIP, OBMC, RBRP have experienced little customer interest (issues include risk/reward imbalance, limited market, lack of marketing emphasis)
- **Contracts – Simplification efforts have been successful**
  – E.g. RBRP only 2 pages & SCE's BIP only 1 page
  – May still be more that could be done?
- **Utility administrative processes can be lengthy due to many depts. needing to "touch" process**

Operations and Portfolio Considerations

- **No critical operation issues identified – But…mostly just test events since the crisis**
  – Recent events may provide new information
  – Communications channels have been expanded (now direct phone, email & pager as well as fax)
  – I6 utilization of older RTU technology is challenging for SCE but works for customers
- **Portfolio Considerations & Other**
  – Is participation driven more by blackout concern or price discounts?
  – Portfolio Complexity
  – Rates' Interrelationships & Interaction
  – Joint Program Resource Level – "pancaking" of potential

Interruptible Scope Next steps

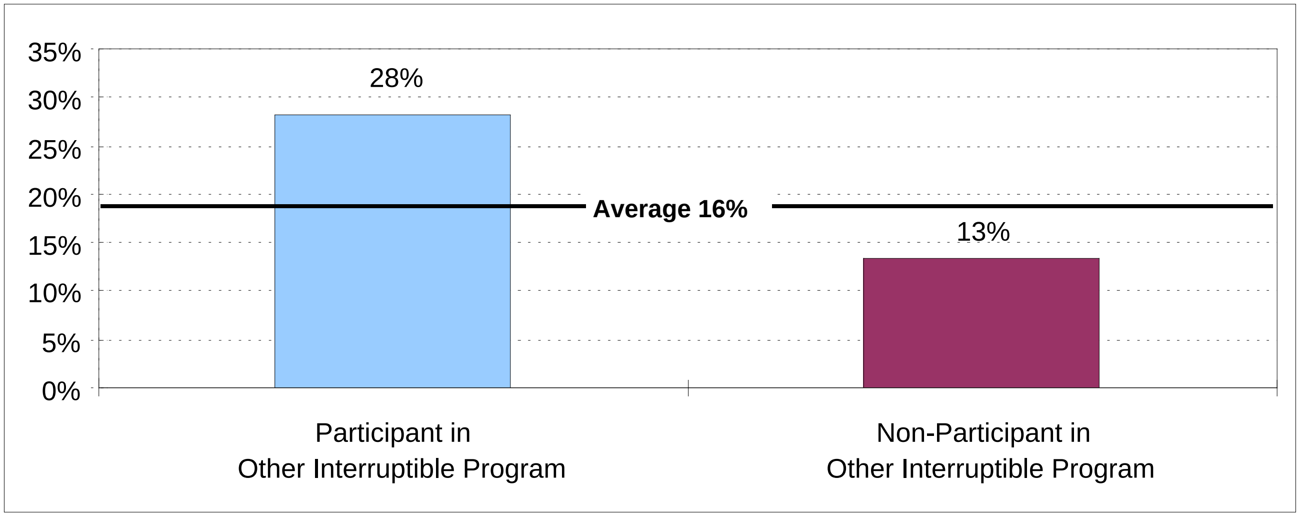
- **Compile Event History (in progress)**
- **Rate Feature Comparison Table (in progress)**
- **Continue to Assess Issues Identified**
- **Develop Interview Guide for Customer Interviews (~15)**

Summary and Q&A on Non-Part Market Survey Report (15 minutes)

- **Brief summary of potential and recommendations**
- **Full results available in 8/5 report and 7/13 WG2 workshop presentation**

Technical and Economic Potential Estimates

- **Technical Potential vs. Economic Potential**
  - Potential estimates based on customer self-reports and estimated coincident peak demand (9,000 MW)
- **Average technical potential reported ~ 16 percent**
  - Initial estimates indicate total MW reduction ~ 1,200 to 1,800 MW
  - Overlap with the IOUs' current interruptible participants



Technical and Economic Potential Estimates

- **Economic potential reported (for < 5% bill savings)**

	5% Reduction	15% Reduction
Estimated Coincident Demand	9,000 MW	9,000 MW
Percent of the Market Willing to Reduce for a 5% or less Bill Reduction	21%	12%
MW of Demand Willing to Reduce	95 MW	158 MW
Percent of Total Demand	1.1%	1.8%

- **Majority of market willing to consider specific DR actions for a few summer afternoons.**
- **Significant DR potential reported across all eligible size groups**

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Non-Part Report Recommendations

- Increase financial benefits of participation or decreasing customer "Hassle Costs"
- Aggressively market new CPP "No Risk" Bill Protection Plan
- Reduce 100 kW DBP bid minimum or allow for chain aggregation
- Utilize existing and consider expanding technical support materials and related tools

Non-Part Report Recommendations – Market Barriers

- **Focus on mitigating top customer-perceived market barriers**
  - "Effects on Products or Productivity" – Segment-specific case studies that provide successful DR strategies
  - "Inability to Reduce Peak Loads" – Customer-specific technical assistance to identify load reduction opportunities, consider incentives for software/equipment (subject to participation requirements & cost-effectiveness constraints)
  - "Level of On-peak Prices or Non-performance Penalties" –Emphasis on the no risk/low risk attributes of DBP and CPP
  - "Amount of Potential Bill Savings" – Bill savings as a fraction of monthly/summer bills
  - "Uncertainty over Future Program Changes" – Consistency in peak load reduction program, guarantee minimum program features for period of time

Upcoming Data Collection and Evaluation Activities

Upcoming Data Collection Activities

CPP/DBP

- Participant Interval Data (in progress)
- Post-Event Survey (in progress)
- Participant End-Use Metering Data
- Fall Participant Interviews
- Fall PM & Related Process Interviews

DRP/Interruptibles (New to WG2 Eval Scope)

- PM & Related Interviews
- Customer Interviews
- Previous Participant Drop-out Interviews

Upcoming Evaluation Activities

- **End of Summer Program Evaluation**
  - **Impact Evaluation**
    - CPP & DBP
    - Interval Meter Baseline Modeling
    - Baseline Diagnostics and Impact Estimation
    - End-Use Metering Results to better understand DR impacts, potential, constraints
  - **Process Evaluation**
    - Program Manager and participant interviews
  - **Market Evaluation**
    - End of Summer Participant Interviews
    - Non-Participants Interviews
      - Drop-outs, Non-Signups

Impact Evaluation

- General Objectives
  - Program Impact Estimates
  - Impact Attribution – end-use, technology or behavior driven
  - Gain insights for continued development of DR programs
- Approach
  - Simulation Methods –"representative-day" approach
  - Non-Participant group
- Data Sources
  - Interval meter data
  - Surveys: Post-Event, Participant, On-site
  - Prior Information
  - Event day data – trigger, weather, bids

Proposed Evaluation Timeline

		Month				
Activity Type	**Activity**	**July**	**Aug.**	**Sept**	**Oct.**	**Nov.**
	Obtain Weekly and Monthly Interval Data	X	X	X	X	X
	Conduct Participant On-Site Surveys	X				
	Conduct Participant Sub-Metering	X	X			
	Conduct Secondary Research on Related Programs	X	X			
	Conduct Periodic Post-Event Surveys		X			
	Conduct End of Summer Participant Interviews			X		
	Conduct End of Summer Utility Interviews			X		
Analysis	Document Program Processes	X	X	X		
	Assess Program Processes	X	X	X		
	Develop Market Assessment	X				
	Estimate Load Impacts		X	X	X	
	Collect and Analyze Sub-Metering Data	X	X	X	X	
Reporting	Initial Process & Market Findings	X	X			
	Preliminary Load Impact Results			X	X	
	Final Report					X

Additional Discussion (30 minutes)